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Fred Dacimo
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Operations License Renewal

NL-14-147

December 16, 2014

U.S. Nuclear Regulatory Commission
Document Control Desk
11545 Rockville Pike, TWFN-2 F1
Rockville, MD 20852-2738

SUBJECT: Reply to Request for Additional Information Regarding the License Renewal Application
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

REFERENCES: NRC letter, "Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, SET 2014-01 (TAC Nos. MD5407 and MD5408)" dated April 1, 2014.

Dear Sir or Madam:

Entergy Nuclear Operations, Inc. is providing, in Attachment 1, the additional information requested in the referenced letter pertaining to NRC review of the License Renewal Application (LRA) for Indian Point 2 and Indian Point 3.

The response provided in Attachment 1 contains new regulatory commitments that are identified in the list of regulatory commitments provided in Attachment 3.

If you have any questions, or require additional information, please contact Mr. Robert Walpole, Regulatory Assurance Manager, at 914-254-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 12/16, 2014.

Sincerely,

FRD/rl

A128
NRR

Attachments:

1. Reply to NRC Request for Additional Information Regarding the License Renewal Application

2. License Renewal Application Changes Due To Responses To Requests For Information

3. License Renewal Application IPEC List of Regulatory Commitments Revision 25

cc: Mr. Daniel H. Dorman, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. Dave Wrona, NRC Branch Chief, Engineering Review Branch I
Ms. Kimberly Green, NRC Sr. Project Manager, Division of License Renewal
Mr. Douglas Pickett, NRR Senior Project Manager
Ms. Bridget Frymire, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. John B. Rhodes, President and CEO NYSERDA

ATTACHMENT 1 TO NL-14-147

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION

REGARDING THE

LICENSE RENEWAL APPLICATION

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

REQUEST FOR ADDITIONAL INFORMATION, SET 2014-01
RELATED TO INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION

RAI 3.0.3-1

Background:

Recent industry operating experience (OE) and questions raised during the staff's review of several license renewal applications (LRAs) have resulted in the staff concluding that several aging management programs (AMPs) and aging management review (AMR) items in the LRA may not or do not account for OE involving recurring internal corrosion, corrosion occurring under insulation, managing aging effects of fire water system components, and certain other issues. In order to provide updated guidance, the NRC staff has issued LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation" (ADAMS Accession No. ML13227A361).

Issue:

The staff noted that the updated guidance may not have been incorporated into the respective AMPs and AMR items.

Request:

Provide details on how the updated guidance of LR-ISG-2012-02 has been accounted for in your AMPs and AMR items; or where the revised recommendations will not be incorporated, state an exception and the basis for the exception. If necessary, provide revisions to LRA Section 3 tables, Appendix A, and Appendix B.

Response to RAI 3.0.3-1

A response follows for each of the eight sections of LR-ISG-2012-02.

Response to LR-ISG section A "Recurring Internal Corrosion"

The updated guidance of LR-ISG-2012-02 Section A was reviewed with respect to the IPEC LRA. The past 10 years of plant-specific operating experience for IP2 and IP3 were reviewed to identify recurring internal corrosion as defined in LR-ISG-2012-02, Section A. Based on these reviews, loss of material due to general, pitting and crevice corrosion is considered recurring internal corrosion applicable to both IP2 and IP3. Loss of material due to general, pitting and crevice corrosion leading to through-wall leaks has occurred at least once in each of three refueling cycles for both units in the last 10 years. Piping components of the following systems for both IP2 and IP3 are susceptible to recurring internal corrosion.

- Service water
- Fire protection – water
- City water

Service Water

The Service Water Integrity Program implements the guidelines of NRC Generic Letter 89-13, including routine inspection and maintenance to ensure that degradation due to corrosion, erosion and biofouling cannot prevent safety-related systems cooled by service water from satisfactorily performing their intended functions. As concluded in NUREG-1930, the effects of aging are adequately managed by the Service Water Integrity Program so that the intended functions are maintained. However, minor corrosion issues that do not compromise the intended functions of the service water system still occur. Carbon steel service water system piping is internally lined with cement, which is very effective in protecting the carbon steel piping. Where discontinuities in the cement lining (such as at piping segment welds) allow the service water to directly contact the carbon steel, corrosion can occur. This corrosion can result in a through-wall leak. Stainless steel and copper alloy piping components also develop through-wall leaks due to localized pitting corrosion. Based on operating experience, such leaks have had no impact on system performance and have not threatened the structural integrity of the piping or the safety function of nearby equipment.

Through-wall leakage is identified and reported by plant personnel during their normal activities or by engineering personnel during system walkdowns. The leakage is then evaluated under the corrective action program, which includes operability or functionality assessment of structural integrity and determination of appropriate corrective action.

Repairs or replacements of safety-related piping are implemented under the Entergy ASME Section XI Repair/Replacement Program, which implements the requirements of IWA-4000.

Fire Protection – Water

The Fire Water System Program includes wall thickness evaluations of fire protection piping using volumetric testing to identify loss of material due to corrosion and ensure that wall thickness is within the required structural limits. These inspections were performed for IP2 before the end of its original operating term. The inspections identified no unacceptable wall thinning. However, minor corrosion issues that do not compromise the intended functions of the fire protection – water system have occurred in the carbon steel piping components exposed to city (potable) water. Localized corrosion has resulted in minor through-wall leaks that have no

impact on system performance and do not threaten the structural integrity of the piping or the safety function of nearby equipment.

City Water

The Periodic Surveillance and Preventive Maintenance Program will monitor corrosion of the city water system to assure it can perform its intended functions. However, minor corrosion issues that do not compromise the intended functions of the city water system have occurred in the carbon steel and copper alloy piping components exposed to city (potable) water. Localized corrosion has resulted in minor through-wall leaks that have no impact on system performance and do not threaten the structural integrity of the piping or the safety function of nearby equipment.

Through-wall leaks in the fire protection – water and city water systems meet the definition of recurring internal corrosion since they exceed the 50 percent wall thickness criterion in LR-ISG-2012-02, Section A. However, based on past operating experience, they do not compromise the intended functions of these or any other system, and do not warrant aging management program activities beyond those provided by established aging management programs and the corrective action program. Through-wall leakage in these systems is identified and reported by plant personnel during their normal activities or by engineering personnel during system walkdowns. When identified, the leak is documented in the corrective action program. Depending on the size of the line, the size of the leak, and its proximity to other plant equipment, NDE may be used to characterize the extent of the corrosion in order to plan the best repair method, or the leak may be patched or repaired.

The service water, fire protection – water and city water systems for IP2 and IP3 include buried piping. Although leaks in buried piping are possible, underground leaks large enough to affect the function of these systems are not expected based on operating experience with the above-ground portions of these systems. If large leaks were to occur, they would be expected to develop slowly and would be detectable by changes in system performance (e.g., changes in instrumentation readings or reduced cooling capacity), changes in system operation (e.g., more frequent pressure maintenance / jockey pump operation), or by the appearance near the leak of wetted ground, sink holes, or other ground anomalies. Accessible portions of safety-related buried service water piping will be internally inspected by robotic crawler or manual crawl-through once during the first 10 years of the period of extended operation.

The actions used to manage the minor corrosion issues in the service water, fire protection – water and city water systems at IP2 and IP3 have been effective. The through-wall leaks resulting from recurring internal corrosion in these systems have not resulted in a loss of system intended function, have not affected the structural integrity of system components, and have not caused a loss of a safety function in nearby equipment.

The Service Water Integrity Program described in LRA Section B.1.34 will be enhanced to incorporate the actions used to manage the minor corrosion issues in the service water system. Revisions to LRA Sections A.2.1.33, A.3.1.33, B.1.34, and Section 3.3 tables are provided in Attachment 2.

Response to LR-ISG section B "Representative Minimum Sample Size for Periodic Inspections in GALL Report AMP XI.M38, 'Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components'."

The updated guidance of LR-ISG-2012-02 Section B was reviewed with respect to the IPEC LRA. This section provides changes for NUREG-1801 XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that inspections performed under this program include a representative sample on a periodic basis.

The IPEC programs credited for managing the effects of aging during the period of extended operation are described in IPEC LRA, Appendix B. None of the programs described in IPEC LRA Appendix B are compared to XI.M38. With respect to NUREG-1801 Section XI.M38, IPEC LRA Table B-2 states, "The External Surfaces Monitoring Program [B.1.11] or the Periodic Surveillance and Preventive Maintenance Program [B.1.29] manage the effects of aging on internal surfaces of piping and ducting components."

The External Surfaces Monitoring Program described in IPEC LRA Section B.1.11 is credited with managing loss of material from internal surfaces, for situations in which internal and external material and environment combinations are the same such that external surface condition is representative of internal surface condition. This program contains provisions for inspection of surfaces at frequencies that assure the effects of aging are managed. In Section 3.0.3.2.5, "External Surfaces Monitoring Program," (page 3-78) of the SER for IPEC license renewal (NUREG-1930 Volume 2, published November 2009), the NRC staff "concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation."

The Periodic Surveillance and Preventive Maintenance Program described in IPEC LRA Section B.1.29 includes periodic inspections of representative samples to manage aging effects not managed by other aging management programs. Section 3.0.3.3.7, "Periodic Surveillance and Preventive Maintenance Program," (page 3-216) of the SER for IPEC license renewal (NUREG-1930 Volume 2, published November 2009) states, "On the basis of its review of the applicant's Periodic Surveillance and Preventive Maintenance Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation."

Because none of the programs described in IPEC LRA Appendix B are compared to XI.M38 and the programs used in lieu of XI.M38 provide for periodic inspections of representative samples of components, no changes to the IPEC LRA are necessary to account for the guidance of Section B of LR-ISG-2012-02.

Response to LR-ISG section C "Flow Blockage of Water-Based Fire Protection System Piping."

The updated guidance of LR-ISG-2012-02 Section C was reviewed with respect to the IPEC LRA. Entergy will perform the tests and inspections for fire water system blockage at IP2 and IP3 as recommended by LR-ISG-2012-02, with exceptions listed in the revised LRA Section B.1.14.

Revisions to LRA Sections A.2.1.13, A.3.1.13, B.1.14 and Section 3.3 tables are provided in Attachment 2.

Response to LR-ISG section D "Revisions to the scope and inspection recommendations of GALL Report AMP XI.M29, "Aboveground Metallic Tanks."

The updated guidance of LR-ISG-2012-02 Section D was reviewed with respect to the IPEC LRA. The Aboveground Steel Tanks Program described in IPEC LRA Section B.1.1 will manage the aging effects for tanks in the scope of the program consistent with the guidance of LR-ISG-2012-02. There are no indoor tanks within the scope of this program as defined in the ISG.

The outdoor tanks within the scope of the program are the IP1 city water tank, IP1 condensate storage tanks, IP2 condensate storage tank, IP2 GT2/3 fuel oil tank (for managing exterior aging effects only), IP2 primary water storage tank, IP2 refueling water storage tank, IP3 condensate storage tank, IP3 primary water storage tank, and IP3 refueling water storage tank.

The Aboveground Steel Tanks Program does not manage the effects of aging on the fire water storage tanks. The Fire Water System Program (described in LRA Sections A.2.1.13, A.3.1.13 and B.1.14) manages the effects of aging on the fire water storage tanks in accordance with the recommendations of LR-ISG-2012-02. The Diesel Fuel Monitoring Program manages the effects of aging on the IP2 GT2/3 fuel oil tank interior.

Revisions to LRA Sections A.2.1.1, A.3.1.1, B.1.1, and Sections 3.2, 3.3 and 3.4 are provided in Attachment 2. These revisions remove operating experience discussion in Section B.1.1 related to tank surfaces that are no longer covered by the Aboveground Steel Tanks Program.

Response to LR-ISG section E "Corrosion Under Insulation."

The updated guidance of LR-ISG-2012-02 Section E was reviewed with respect to the IPEC LRA. The following items discuss each applicable lettered paragraph under the summary of changes in LR-ISG-2012-02 Section E regarding corrosion under insulation (CUI).

a. LR-ISG-2012-02, Section E.iii.a recommends periodic inspections during each 10-year period of the period of extended operation (PEO). IPEC inspections for CUI will be conducted during each 10-year period of the PEO.

b. LR-ISG-2012-02, Section E.iii.b provides recommendations for inspection of insulated components, except for tanks. IPEC will inspect insulated components in accordance with those recommendations. For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point) and insulated outdoor components, insulation will be removed for visual inspection of component surfaces. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum) or, for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type.

c. LR-ISG-2012-02, Section E.iii.c provides recommendations for inspection of indoor insulated tanks exposed to condensation and outdoor insulated tanks. Because IPEC in-scope indoor insulated tanks operate above the dew point, they are not subject to condensation on the external surface. In-scope outdoor insulated tanks at IPEC have tightly adhering insulation. See discussion of tightly adhering insulation in item e below.

d. LR-ISG-2012-02, Section E.iii.d recommends selecting inspection locations based on the likelihood of CUI. For example, CUI is more likely for components that are alternately wet and dry in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point. IPEC inspection locations will be based on the likelihood of CUI.

   Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection:

   - No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction.
   - No evidence of cracking.

   If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams or joints), periodic inspections under the insulation will continue.

e. LR-ISG-2012-02, Section E.iii.e provides recommendations for inspecting components with tightly adhering insulation. IPEC will inspect components with tightly adhering

insulation in accordance with the recommendations of the ISG. Tightly adhering insulation that is impermeable to moisture will be removed to allow for inspection if there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Components with tightly adhering insulation constitute a separate population from the remainder of in-scope insulated components. The entire population of in-scope accessible component surfaces covered with tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of components with other types of insulation. These inspections will not be credited towards the inspection quantities for components with other types of insulation.

Revisions to text and tables in LRA Sections 3.2, 3.3, 3.4, A.2.1.10, A.3.1.10, and B.1.11 are provided in Attachment 2. In these revisions, line items are added to the aging management review results tables for each IPEC system determined susceptible to CUI.

Response to LR-ISG section F "External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41, 'Buried and Underground Piping and Tanks'."

The updated guidance of LR-ISG-2012-02 Section F was reviewed with respect to the IPEC LRA. This section provides changes for NUREG-1801, XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to allow the condition of internal surfaces of buried and underground piping to be inferred from inspections of the interior surfaces of accessible piping where the material, environment, and aging effects of the buried or underground component are similar to those of the accessible component.

This change in the ISG provides an allowance to use this approach for interior surfaces of buried and underground piping. It neither recommends use of the approach nor prohibits another approach to managing the effects of aging. Therefore, no changes to the IPEC LRA are necessary to account for the guidance of Section F of LR-ISG-2012-02.

Response to LR-ISG section G "Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38."

The updated guidance of LR-ISG-2012-02 Section G was reviewed with respect to the IPEC LRA. This section provides changes for NUREG-1801, XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to remove the term "hydrotesting" from the program description.

The IPEC programs credited for managing the effects of aging during the period of extended operation are described in IPEC LRA, Appendix B. None of the programs described in IPEC LRA Appendix B are compared to XI.M38. With respect to NUREG-1801, Section XI.M38, IPEC LRA Table B-2 states, "The External Surfaces Monitoring Program [B.1.11] or the Periodic Surveillance and Preventive Maintenance Program [B.1.29] manage the effects of aging on internal surfaces of piping and ducting components." Neither of these programs provide for the use of hydrotesting.

Because none of the programs described in IPEC LRA Appendix B that are used in lieu of XI.M38 rely on or provide for the use of hydrotesting, no changes to the IPEC LRA are necessary to account for the guidance of Section G of LR-ISG-2012-02.

Response to LR-ISG section H "Key Miscellaneous Changes to the GALL Report and SRP-LR."

The updated guidance of LR-ISG-2012-02 Section H was reviewed with respect to the IPEC LRA. Section H, subsection v, item e was the only item identified with a potential impact on the IPEC LRA. This item added a new aging effect for NUREG-1801. "Reduced thermal insulation resistance" in jacketed insulation of various types exposed to indoor or outdoor air was added for steam and power conversion systems.

Entergy reviewed the steam and power conversion systems piping at IPEC. Piping insulation is not credited for thermal resistance in support of any safety function of these systems. Consequently, reduction of thermal insulation resistance is not an aging effect requiring management, and no changes to the IPEC LRA are necessary to account for the guidance of Section H of LR-ISG-2012-02.

ATTACHMENT 2 TO NL-14-147

LICENSE RENEWAL APPLICATION

CHANGES DUE TO RESPONSES TO REQUESTS FOR INFORMATION

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

Revisions to LRA text and tables are provided below with additions underlined and deletions marked through.

3.2.2.1.4 Safety Injection System

Aging Management Programs

The following aging management programs manage the aging effects for safety injection system components.

- Aboveground Steel Tanks
- Bolting Integrity
- Boric Acid Corrosion Prevention
- Buried Piping and Tanks Inspection
- External Surfaces Monitoring
- Heat Exchanger Monitoring
- Oil Analysis
- Periodic Surveillance and Preventive Maintenance
- Selective Leaching
- Water Chemistry Control – Closed Cooling Water
- Water Chemistry Control – Primary and Secondary

3.2.2.2.3 Loss of Material due to Pitting and Crevice Corrosion

5. Loss of material from pitting and crevice corrosion could occur for partially encased stainless steel tanks exposed to raw water due to cracking of the perimeter seal from weathering. ~~At IPEC the bottom of outdoor stainless steel tanks in the ESF systems are not exposed to raw water because the design precludes the entry of water under the tank. In addition to a perimeter seal under the tank lip, the tanks have been grouted behind the seal between the concrete foundation and the tank bottom to a depth of eighteen inches. This design will not allow water leakage from the outside to get under the tank.~~ Inspections will be conducted in accordance with the Aboveground Steel Tanks Program to identify degradation of external surfaces of tank bottoms exposed to soil or concrete. ~~This item is therefore not applicable.~~

Table 3.2.1, Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of NUREG-1801

Table 3.2.1: Engineered Safety Features, NUREG-1801 Vol. 1					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-49	Stainless steel piping, piping components, piping elements, and tanks exposed to treated borated water	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Consistent with NUREG-1801. The Water Chemistry Control – Primary and Secondary Program manages loss of material of stainless steel components exposed to treated borated water. Loss of material for the refueling water storage tanks is also managed by the Aboveground Steel Tanks Program.

In Notes for Tables 3.2.2-1-IP2 through 3.2.2-5-IP3 at the end of LRA Table 3.2.1, add the following Plant-Specific Note 209.

209. Program provisions apply for outdoor insulated components.

Table 3.2.2-2-IP2: Containment Spray System, Summary of Aging Management Review

Table 3.2.2-2-IP2: Containment Spray System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 209
Insulated piping components	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	External Surfaces Monitoring	–	–	H, 209

Table 3.2.2-2-IP3: Containment Spray System, Summary of Aging Management Review

Table 3.2.2-2-IP3: Containment Spray System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 209
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	External Surfaces Monitoring	–	–	H, 209

Table 3.2.2-4-IP2: Safety Injection Systems, Summary of Aging Management Review

Table 3.2.2-4-IP2: Safety Injection Systems

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 209
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	External Surfaces Monitoring	–	–	H, 209
Tank	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	~~External Surfaces Monitoring~~ Aboveground Steel Tanks	–	–	G
Tank	~~Pressure~~ boundary	Stainless steel	Concrete (ext)	~~None~~ Loss of Material	~~None~~ Aboveground Steel Tanks	~~– V.F-14 (EP-20)~~	~~–3.2.1-55~~	~~A~~ H
Tank	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Aboveground Steel Tanks	V.D1-30 (EP-41)	3.2.1-49	E

Table 3.2.2-4-IP3: Safety Injection Systems, Summary of Aging Management Review

Table 3.2.2-4-IP3: Safety Injection Systems

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 209
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	External Surfaces Monitoring	–	–	H, 209
Tank	Pressure boundary	Stainless steel	Air – outdoor (ext)	Loss of material	Aboveground Steel Tanks ~~External Surfaces Monitoring~~	–	–	G
Tank	Pressure boundary	Stainless steel	Concrete (ext)	Loss of Material ~~None~~	Aboveground Steel Tanks ~~None~~	~~V.F-14 (EP-20)~~	~~3.2.1-55~~	HA
Tank	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Aboveground Steel Tanks	V.D1-30 (EP-41)	3.2.1-49	E

3.3.2.1.7 Primary Makeup Water

Aging Management Programs

The following aging management programs manage the aging effects for primary makeup water system components.

- Aboveground Steel Tanks
- Bolting Integrity
- External Surfaces Monitoring
- Water Chemistry Control – Primary and Secondary

Table 3.3.1, Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of NUREG-1801

Table 3.3.1: Auxiliary Systems, NUREG-1801 Vol. 1					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-58	Steel external surfaces exposed to air – indoor uncontrolled (external), air - outdoor (external), and condensation (external)	Loss of material due to general corrosion	External Surfaces Monitoring	No	Consistent with NUREG-1801 for most steel components. The External Surfaces Monitoring Program manages loss of material for external surfaces. For some steel components of the fire protection – CO2, halon, and RCP oil collection systems, the Fire Protection Program manages loss of material using periodic visual inspections. For fire protection system tanks, the Fire Water System Program manages loss of material using periodic visual and NDE inspections. The Periodic Surveillance and Preventive Maintenance Program periodically inspects external steel surfaces of components inside the fan cooler units of the containment cooling and filtration system to manage loss of material.

In Notes for Tables 3.3.2-1-IP2 through 3.3.2-19-62-IP3 at the end of LRA Table 3.3.1, add the following Plant-Specific Note 320.

320. Program provisions apply for indoor insulated components that operate below the dew point and outdoor insulated components.

Table 3.3.2-2-IP2: Service Water System, Summary of Aging Management Review

Table 3.3.2-2-IP2: Service Water System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320
Piping components	Pressure boundary	Carbon steel	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H
Piping components	Pressure boundary	Copper alloy	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H
Piping components	Pressure boundary	Stainless steel	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H

Table 3.3.2-2-IP3: Service Water System, Summary of Aging Management Review

Table 3.3.2-2-IP3: Service Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320
Piping components	Pressure boundary	Carbon steel	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H
Piping components	Pressure boundary	Copper alloy	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H
Piping components	Pressure boundary	Stainless steel	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H

Table 3.3.2-7-IP2: Primary Water Makeup System, Summary of Aging Management Review

Table 3.3.2-7-IP2: Primary Water Makeup System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320
Insulated tank	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	Aboveground Steel Tanks	–	–	H, 320
Insulated tank	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	Aboveground Steel Tanks	–	–	H, 320
~~Tank~~	~~Pressure boundary~~	~~Stainless steel~~	~~Air - outdoor (ext)~~	~~Loss of material~~	~~External Surfaces Monitoring~~	–	–	~~G~~
Tank	~~Pressure~~ boundary	Stainless steel	Concrete (ext)	Loss of material ~~None~~	Aboveground Steel Tanks ~~None~~	~~–VII.J-17 (AP-19)~~	~~–3.3.1-96~~	~~HA~~
Tank	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Aboveground Steel Tanks	VIII.E-40 (S-13)	3.4.1-6	E

Table 3.3.2-7-IP3: Primary Water Makeup System, Summary of Aging Management Review

Table 3.3.2-7-IP3: Primary Water Makeup System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320
Insulated tank	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	Aboveground Steel Tanks	–	–	H, 320
Insulated tank	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	Aboveground Steel Tanks	–	–	H, 320
~~Tank~~	~~Pressure boundary~~	~~Stainless steel~~	~~Air - outdoor (ext)~~	~~Loss of material~~	~~External Surfaces Monitoring~~	–	–	~~G~~
Tank	Pressure boundary	Stainless steel	Concrete (ext)	Loss of material ~~None~~	Aboveground Steel Tanks ~~None~~	~~VII.J-17 (AP-19)~~	~~3.3.1-96~~	~~HA~~
Tank	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Aboveground Steel Tanks	VIII.E-40 (S-13)	3.4.1-6	E

Table 3.3.2-8-IP2: Heating, Ventilation and Cooling, Summary of Aging Management Review

Table 3.3.2-8-IP2: Heating, Ventilation and Cooling								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-8-IP3: Heating, Ventilation and Cooling, Summary of Aging Management Review

Table 3.3.2-8-IP3: Heating, Ventilation and Cooling								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-9-IP3: Containment Cooling and Filtration, Summary of Aging Management Review

Table 3.3.2-9-IP3: Containment Cooling and Filtration								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-10-IP2: Control Room Heating, Ventilation and Cooling, Summary of Aging Management Review

Table 3.3.2-10-IP2: Control Room Heating, Ventilation and Cooling								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-10-IP3: Control Room Heating, Ventilation and Cooling, Summary of Aging Management Review

Table 3.3.2-10-IP3: Control Room Heating, Ventilation and Cooling								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-11-IP2: Fire Protection – Water, Summary of Aging Management Review

Table 3.3.2-11-IP2: Fire Protection – Water

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Gray cast iron	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Tank	Pressure boundary	Carbon steel	Air – indoor (ext)	Loss of material	~~External Surfaces Monitoring~~ Fire Water System	VII.I-8 (A-77)	3.3.1-58	~~A~~ E
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	~~Aboveground Steel Tanks~~ Fire Water System	~~VII.H1-11 (A-95)~~ VII.I-9 (A-78)	~~3.3.1-40~~ 3.3.1-58	~~C~~E
Tank	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	~~Aboveground Steel Tanks~~ Fire Water System	–	–	G

Table 3.3.2-11-IP3: Fire Protection – Water, Summary of Aging Management Review

Table 3.3.2-11-IP3: Fire Protection – Water								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Gray cast iron	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Tank	Pressure boundary	Carbon steel	Air – indoor (ext)	Loss of material	~~External Surfaces Monitoring~~ Fire Water System	VII.I-8 (A-77)	3.3.1-58	~~A~~ E
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	~~Aboveground Steel Tanks~~ Fire Water System	~~VII.H1-11 (A-95)~~ VII.I-9 (A-78)	~~3.3.1-40~~ 3.3.1-58	~~C~~E
Tank	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	~~Aboveground Steel Tanks~~ Fire Water System	–	–	G

Table 3.3.2-14-IP2: Emergency Diesel Generators, Summary of Aging Management Review

Table 3.3.2-14-IP2: Emergency Diesel Generators								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-14-IP3: Emergency Diesel Generators, Summary of Aging Management Review

Table 3.3.2-14-IP3: Emergency Diesel Generators								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-17-IP2: City Water, Summary of Aging Management Review

Table 3.3.2-17-IP2: City Water								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Gray cast iron	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Carbon steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Gray cast iron	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Aboveground Steel Tanks ~~Periodic Surveillance and Preventive Maintenance~~	–	–	G, 305

Table 3.3.2-17-IP3: City Water, Summary of Aging Management Review

Table 3.3.2-17-IP3: City Water								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Gray cast iron	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Carbon steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Gray cast iron	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Air - outdoor (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-1-IP2: Auxiliary Steam System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-1-IP2: Auxiliary Steam System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-2-IP2: Conventional Closed Cooling System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-2-IP2: Conventional Closed Cooling System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-7-IP2: City Water System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-7-IP2: City Water System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-11-IP2: Fire Protection System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-11-IP2: Fire Protection System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-13-IP2: Fresh Water Cooling System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-13-IP2: Fresh Water Cooling System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-16-IP2: House Service Boiler System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-16-IP2: House Service Boiler System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-17-IP2: Heating, Ventilation and Air Conditioning System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-17-IP2: Heating, Ventilation and Air Conditioning System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-39-IP2: Service Water System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-39-IP2: Service Water System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320
Piping components	Pressure boundary	Carbon steel	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H
Piping components	Pressure boundary	Copper alloy	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H

Piping components	Pressure boundary	Stainless steel	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H

Table 3.3.2-19-43-IP2: Water Treatment Plant System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-43-IP2: Water Treatment Plant System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated tank	Pressure boundary	Carbon steel	Air - outdoor (ext)	Loss of material	Aboveground Steel Tanks	–	–	H, 320

Table 3.3.2-19-13-IP3: City Water Makeup System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-13-IP3: City Water Makeup System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Insulated piping components	Pressure boundary	Gray cast iron	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-20-IP3: Fire Water System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-20-IP3: Fire Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Gray cast iron	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320

Table 3.3.2-19-56-IP3: Service Water System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-56-IP3: Service Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Piping components	Pressure boundary	Carbon steel	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H
Piping components	Pressure boundary	Copper alloy	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H
Piping components	Pressure boundary	Stainless steel	Raw water (int)	Recurring internal corrosion	Service Water Integrity	–	–	H

Table 3.3.2-19-58-IP3: Turbine Hall Closed Cooling System, Nonsafety-Related Components Potentially Affecting Safety Functions, Summary of Aging Management Review

Table 3.3.2-19-58-IP3: Turbine Hall Closed Cooling System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 320
Insulated piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 320

Table 3.4.1: Summary of Aging Management Programs for the Steam and Power Conversion System Evaluated in Chapter VIII of NUREG-1801

Table 3.4.1: Steam and Power Conversion Systems, NUREG-1801 Vol. 1					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-6	Steel and stainless steel tanks exposed to treated water	Loss of material due to general (steel only) pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Consistent with NUREG-1801. Loss of material in steel and stainless steel tanks exposed to treated water is managed by the Water Chemistry Control – Primary and Secondary Program. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program. Loss of material for the primary makeup water tanks (Tables 3.3.2-7-IP2 and IP3) and condensate storage tanks is also managed by the Aboveground Steel Tanks Program. See Section 3.4.2.2.2 item 1 and Section 3.4.2.2.7 item 1.
3.4.1-30	Steel piping, piping components, and piping elements exposed to air outdoor (internal) or condensation (internal)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	~~The only s~~Steel components with intended functions in the steam and power conversion systems with internal surfaces exposed to outdoor air or condensation are the condensate storage tanks, main steam safety valve (MSSV) tailpipes, and the atmospheric dump valve (ADV) silencers. The condensate storage tank vapor space is nitrogen blanketed but the environment is conservatively assumed to be

Table 3.4.1: Steam and Power Conversion Systems, NUREG-1801 Vol. 1					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
					condensation. Loss of material for these tank surfaces is managed by ~~controlling the tank water chemistry with the Water Chemistry Control – Primary and Secondary Program. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program.~~ the Aboveground Steel Tanks Program. Loss of material for the MSSV tailpipes and the ADV silencers will be managed by the Periodic Surveillance and Preventive Maintenance Program.

In Notes for Tables 3.4.2-1-IP2 through 3.4.2-4-IP3, at the end of LRA Table 3.4.1, add the following Plant-Specific Note 408.

408. Program provisions apply for indoor insulated components that operate below the dew point and outdoor insulated components.

Table 3.4.2-3-IP2, Auxiliary Feedwater System, Summary of Aging Management Review

Table 3.4.2-3-IP2: Auxiliary Feedwater System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 408
Tank	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Aboveground Steel Tanks ~~Water Chemistry Control – Primary and Secondary~~	VIII.G-34 (SP-60)	3.4.1-30	E, 402
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Aboveground Steel Tanks	VIII.G-41 (S-13)	3.4.1-6	E

Table 3.4.2-3-IP3, Auxiliary Feedwater System, Summary of Aging Management Review

Table 3.4.2-3-IP3: Auxiliary Feedwater System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 408

Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 408
Tank	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Aboveground Steel Tanks ~~Water Chemistry Control – Primary and Secondary~~	VIII.G-34 (SP-60)	3.4.1-30	E, 402
Tank	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Aboveground Steel Tanks	VIII.G-41 (S-13)	3.4.1-6	E

Table 3.4.2-5-4-IP2, City Water System, Components Required to Support AFW Pump Room Fire Event, Summary of Aging Management Review

Table 3.4.2-5-4-IP2: City Water System (CYW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	–	–	H, 408
Insulated piping components	Pressure boundary	Carbon steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	–	–	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	External Surfaces Monitoring	–	–	H, 408

Table 3.4.2-5-5-IP2, Wash Water System, Components Required to Support AFW Pump Room Fire Event, Summary of Aging Management Review

Table 3.4.2-5-5-IP2: Wash Water System (WW) Components

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	-	-	H, 408
Insulated piping components	Pressure boundary	Gray cast iron	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	-	-	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Loss of material	External Surfaces Monitoring	-	-	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Air - outdoor (ext)	Cracking	External Surfaces Monitoring	-	-	H, 408

Table 3.4.2-5-9-IP2, Service Water System, Components Required to Support AFW Pump Room Fire Event, Summary of Aging Management Review

Table 3.4.2-5-9-IP2: Service Water System (SW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Insulated piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	-	-	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	-	-	H, 408
Insulated piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	-	-	H, 408

A.2.1.1 Aboveground Steel Tanks Program

The Aboveground Steel Tanks Program ~~is an existing program that~~ manages loss of material on outdoor tanks situated on soil or concrete. The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice including the use of sealant or caulking at the concrete to tank interface of outdoor tanks. External visual examinations (supplemented with physical manipulation of caulking or sealant) are performed to monitor degradation of uncoated surfaces and of protective paint, coating, and sealants. Surface exams are conducted to detect cracking when susceptible materials are used (e.g., stainless steel. aluminum). A sample of the external surfaces of insulated tanks is inspected. Internal visual and surface (when necessary to detect cracking) examinations are conducted as well as measuring the thickness of the tank bottoms to ensure that significant degradation is not occurring and that the component intended function is maintained during the period of extended operation. ~~from external surfaces of aboveground carbon steel tanks by periodic visual inspection of external surfaces and thickness measurement of locations that are inaccessible for external visual inspection.~~

The Aboveground Steel Tanks Program will be enhanced to include the following tank inspection details[1].

- ~~Revise applicable procedures to perform thickness measurements of the bottom surfaces of the condensate storage tank, city water tank, and fire water tank, once during the first 10 years of the period of extended operation.~~

- ~~Revise applicable procedures to require trending of thickness measurements when material loss is detected.~~

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Inspections to identify degradation of inside surfaces of tank shell, roof[3], and bottom inside surface (IS), outside surface (OS)[4, 5]				
Steel	Treated water	Loss of material	Volumetric from OS[6] or visual from IS	One time prior to December 31, 2019[7]
Stainless Steel	Treated water	Loss of material	Volumetric from OS[6] or visual from IS	One time prior to December 31, 2019[7]
Inspections to identify degradation of external surfaces of tank roof, tank shell, and bottom not exposed to soil or concrete[8]				
Steel	Air-indoor uncontrolled Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Stainless Steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking	Surface[9, 10]	Each 10-year period of the period of extended operation
Inspections to identify degradation of tank bottoms and tank shells exposed to soil or concrete				
Steel	Soil or concrete	Loss of material	Volumetric from IS	Each 10-year period of the period of extended operation[11]
Stainless Steel	Soil or concrete	Loss of material	Volumetric from IS	Each 10-year period of the period of extended operation[11]

Tank Inspection Table Notes

1. IPEC LRA Section B.1.9, "Diesel Fuel Monitoring," manages loss of material on the internal surfaces of fuel oil storage tanks.
2. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g. inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated effective at detecting the AERM and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective, the low-frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. An LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom if follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal.
3. Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces.
4. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces.
5. Materials, if any, accumulated on the tank bottom (e.g., sediment, silt) are removed to allow for complete internal inspections of the tank's surfaces.
6. At least 25 percent of the tank surface is inspected using a method capable of precisely determining wall thickness. The inspection method should be demonstrated capable of detecting both general and pitting corrosion.
7. At least one tank for each material and environment combination should be inspected.
8. For tanks with tightly adhering insulation without evidence of damage to the moisture barrier, inspections may consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation. For tanks with caulking or sealant at the concrete to tank interface, visual inspection of the caulking or sealant is performed in conjunction with physical manipulation of the caulking or sealant.
9. An inspection will be performed prior to December 31, 2019. Subsequent inspections are not required if an evaluation conducted prior to December 31, 2019 and at the scheduled time of each subsequent inspection during the PEO demonstrates the absence of chlorides or other deleterious compounds at sufficient levels to cause pitting corrosion, crevice corrosion, or cracking. The evaluation should include soil sampling in the vicinity of the tank (because soil results indicate atmospheric fallout accumulating in the soil and potentially affecting tank surfaces) and sampling of residue on the top and sides of the tank.

10. A minimum of either 25 sections of the tank's surface (e.g., 1-square-foot sections for tank surfaces, 1-linear-foot sections of weld length) or 20 percent of the tank's surface are examined. The sample inspection points are distributed in such a way that inspections occur in those areas most susceptible to degradation (i.e., areas where contaminants could collect, inlet and outlet nozzles, welds).
11. The first inspection will be performed during the first 10 years of the period of extended operation. Subsequent inspections are not required if evaluations conducted at the time of the first inspection and at the scheduled time of each subsequent inspection during the PEO demonstrate that the soil under the tank is not corrosive using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity. The evaluation should include soil sampling from underneath the tank.

Enhancements will be implemented prior to December 31, 2019 ~~the period of extended operation~~.

A.2.1.10 External Surfaces Monitoring Program

The External Surfaces Monitoring Program is an existing program that inspects external surfaces of components subject to aging management review. The program is also credited with managing loss of material from internal surfaces, for situations in which internal and external material and environment combinations are the same such that external surface condition is representative of internal surface condition.

Surfaces that are inaccessible during plant operations are inspected during refueling outages. ~~Surfaces that are insulated are inspected when the external surface is exposed (i.e., during maintenance).~~ Periodic representative surface condition inspections of the in-scope mechanical indoor components under insulation (with process fluid temperature below the dew point) and outdoor components under insulation will be performed during each 10-year period of the period of extended operation. Surfaces are inspected at frequencies to assure the effects of aging are managed such that applicable components will perform their intended function during the period of extended operation.

The External Surfaces Monitoring Program will be enhanced to include the following.

- Guidance documents will be revised to require periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(2).

- Procedures will be revised to specify the following for insulated components.

  - Periodic representative inspections for CUI will be conducted during each 10-year period of the PEO.

  - For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point) and insulated outdoor components, insulation will be removed for visual inspection of component surfaces. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum) or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type.

  - Inspection locations will be based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components that are alternately wet and dry in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point.

    Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection:

- No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction.
- No evidence of cracking

If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue.

- Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Tightly adhering insulation that is impermeable to moisture will be removed to allow for inspection if there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Components with tightly adhering insulation constitute a separate population from the remainder of in-scope insulated components. The entire population of in-scope accessible component surfaces covered with tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of components with other types of insulation. These inspections will not be credited towards the inspection quantities for components with other types of insulation.

Enhancements will be implemented prior to December 31, 2019 ~~the period of extended operation~~.

A.2.1.13 Fire Water System Program

The Fire Water System Program is an existing program that manages water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, fire pump casings, water storage tanks, standpipes, piping, and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes ~~and standards~~. Such testing assures functionality of systems. To determine if ~~significant~~ abnormal corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections are conducted. In addition to NFPA codes, portions of the water-based fire protection system (a) that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect are subject to augmented testing and inspections. Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

In addition, visual inspection results that identify excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program, and a follow-up volumetric wall thickness examination will be performed. ~~wall thickness evaluations of fire protection piping are periodically performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion.~~

A sample of sprinkler heads required for 10 CFR 50.48 will be inspected using the guidance of NFPA 25 (2011~~02~~ Edition) Section 5.3.1.1.1, which states, "Where sprinklers have been in ~~place~~ service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be tested ~~submitted to a recognized testing laboratory for field service testing~~." This sampling will be repeated every 10 years after initial field service testing.

The Fire Water System Program will be enhanced to include the following.

- Revise applicable procedures to include inspection of hose reels for corrosion. In addition, revise the ~~A~~acceptance criteria ~~will be revised~~ to verify no unacceptable signs of degradation.

- Revise Fire Water System Program procedures to replace or test closed ~~S~~sprinkler heads required for 10 CFR 50.48 ~~will be replaced or a sample tested using guidance of~~ in accordance with NFPA 25 (2011~~02~~ ~~e~~Edition), Section 5.3.1.~~1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.~~

- ~~Wall thickness evaluations of fire protection piping will be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function.~~

- Revise Fire Water System Program ~~applicable~~ procedures to inspect the internal surface of the foam-based fire suppression tanks at least once every 10 years. Acceptance criteria will be enhanced to verify no ~~significant~~ abnormal corrosion.

- Revise Fire Water System Program procedures acceptance criteria for the primary auxiliary building exhaust, containment building purge exhaust, and containment building pressure relief charcoal units to ensure partial flow blockage can be detected during air flow testing. (Refer to NFPA-25 (2011 Edition), Section 13.4.3.2.2)

- Revise Fire Water System Program procedures to inspect the nozzles in the charcoal filter units for abnormal corrosion when the charcoal is replaced. (Refer to NFPA-25 (2011 Edition), Sections 13.4.3.2.2 and 14.2)

- Revise Fire Water System Program procedures to inspect for and require replacement of sprinkler heads (nozzles) if they show signs of abnormal corrosion, excessive loading, leakage, or if the glass bulb heat responsive element is found empty. (Refer to NFPA-25 (2011 Edition), Section 5.2.1.1.)

- Revise Fire Water System Program procedures to perform main drain testing in accordance with NFPA 25 (2011 Edition), Section 13.2.5, on 20 percent of the testable automatic standpipes with at least one main drain test in each building. (Refer to NFPA-25 (2011 Edition) Sections 6.3.1.5 and 13.2.5.)

- Revise Fire Water System Program procedures to inspect the interior and exterior of the fire water storage tanks in accordance with NFPA 25 (2011 Edition), Sections 9.2.5.5, 9.2.6 and 9.2.7, with the exception of NFPA Sections 9.2.7.1 and 9.2.7.6. In lieu of testing specified in Section 9.2.7.1, perform holiday testing. In lieu of testing specified in Section 9.2.7.6, perform ultrasonic thickness checks or mechanical measurements of any identified corroded areas at least once every five years.

- Revise Fire Water System Program procedures to inspect and test the deluge system for the boric acid building filter units every two years in accordance with NFPA 25 (2011 Edition), Section 13.4.3.2.2.

- Revise Fire Water System Program procedures to perform an air flow test each refueling outage through the foam system open-head nozzles to ensure there is no blockage, and in the event blockage is identified, provide instruction that the system shall be cleaned and retested. (Refer to NFPA-25 (2011 Edition), Section 13.4.3.2.2.)

- Revise Fire Water System Program procedures to remove, inspect for damage and corroded parts, and clean the strainers associated with the supply line to the electric tunnel, and in the line downstream of the deluge valve for the primary auxiliary building exhaust and containment building purge filtration units every five years or after each flow test. (Refer to NFPA-25 (2011 Edition), Section 10.2.1.7.)

- Revise Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions every five years, or after an extended shutdown of greater than one year, by opening a flushing connection at the end of one main and by removing a closed sprinkler toward the end of one branch line for the purpose of inspecting the interior

for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler heads or nozzles. In the event there are multiple wet pipe systems in a structure, one third will be inspected every five years such that all systems will be inspected during each 15-year period. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

- Revise Fire Water System Program procedures to perform an internal inspection of dry piping every five years, or after an extended shutdown of greater than one year, for the preaction systems associated with the technical support center computer and uninterruptible power supply room, and the preaction system associated with the electric tunnels by removing a sprinkler toward the end of one branch line or using the inspectors test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

- Revise Fire Water System Program procedures to perform an internal inspection of the most remote dry piping downstream of the deluge valves every five years, or after an extended shutdown of greater than one year, for the deluge systems associated with the for the primary auxiliary building, containment purge, containment ventilation, and boric acid building charcoal filters, and the foam deluge systems by removing a sprinkler toward the end of one branch line or using the inspectors test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

- Revise Fire Water System Program procedures to perform an obstruction evaluation if any of the following conditions exist. (Refer to NFPA-25 (2011 Edition), Section 14.3.1.)

  - There is an excessive discharge of material during routine flow tests.
  - An inspector's test valve is clogged during routine testing.
  - Foreign materials are identified during internal inspections.
  - Sprinkler heads are found clogged during removal or testing.

- Pin hole leaks are identified in fire water piping.
- After an extended shutdown.
- There is a 50 percent increase in time it takes for water to flow out the inspector test valve after the associated dry valve is tripped when compared to the original acceptance criteria or last test.

- Revise Fire Water System Program procedures to perform a wall thickness evaluation of any areas identified with excessive accumulation of corrosion products or appreciable localized pitting beyond a normal oxide layer and enter the condition into the corrective action program. (Refer to LR-ISG-2012-02, Section C, iii, (c).)

Enhancements will be implemented prior to ~~the period of extended operation~~ December 31, 2019.

A.2.1.33, Service Water Integrity Program

The Service Water Integrity Program will be enhanced to include the following.

- Revise the appropriate procedures to incorporate actions to manage corrosion issues.
    - When through-wall leaks are detected, the leakage is evaluated under the corrective action program, which includes operability or functionality assessment of structural integrity and determination of appropriate corrective action.
    - Accessible portions of safety-related buried service water piping will be internally inspected by robotic crawler or manual crawl-through once during the first 10 years of the period of extended operation.

The enhancement will be implemented prior to December 31, 2019.

A.3.1.1 Aboveground Steel Tanks Program

The Aboveground Steel Tanks Program ~~is an existing program that~~ manages loss of material on outdoor tanks situated on soil or concrete. The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice including the use of sealant or caulking at the concrete to tank interface of outdoor tanks. External visual examinations (supplemented with physical manipulation of caulking or sealant) are performed to monitor degradation of uncoated surfaces and of protective paint, coating, and sealants. Surface exams are conducted to detect cracking when susceptible materials are used (e.g., stainless steel. aluminum). A sample of the external surfaces of insulated tanks is inspected. Internal visual and surface (when necessary to detect cracking) examinations are conducted as well as measuring the thickness of the tank bottoms to ensure that significant degradation is not occurring and that the component intended function is maintained during the period of extended operation. ~~from external surfaces of aboveground carbon steel tanks by periodic visual inspection of external surfaces and thickness measurement of locations that are inaccessible for external visual inspection.~~

The Aboveground Steel Tanks Program will be enhanced to include the following tank inspection details[1].

- ~~Revise applicable procedures to perform thickness measurements of the bottom surfaces of the condensate storage tank and fire water tanks, once during the first 10 years of the period of extended operation.~~

- ~~Revise applicable procedures to require trending of thickness measurements when material loss is detected.~~

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Inspections to identify degradation of inside surfaces of tank shell, roof[3], and bottom Inside Surface (IS), Outside Surface (OS)[4, 5]				
Steel	Treated water	Loss of material	Volumetric from OS[6] or visual from IS	One time prior to December 31, 2019[7]
Stainless Steel	Treated water	Loss of material	Volumetric from OS[6] or Visual from IS	One time prior to December 31, 2019[7]
Inspections to identify degradation of external surfaces of tank roof, tank shell, and bottom not exposed to soil or concrete[8]				
Steel	Air-indoor uncontrolled Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
Stainless Steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
		Cracking	Surface[9, 10]	Each 10-year period of the period of extended operation
Inspections to identify degradation of tank bottoms and tank shells exposed to soil or concrete				
Steel	Soil or concrete	Loss of material	Volumetric from IS	Each 10-year period of the period of extended operation[11]
Stainless Steel	Soil or concrete	Loss of material	Volumetric from IS	Each 10-year period of the period of extended operation[11]

Tank Inspection Table Notes

1. IPEC LRA section B.1.9, "Diesel Fuel Monitoring" manages loss of material on the internal surfaces of fuel oil storage tanks.
2. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g. inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated effective at detecting the AERM and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low-frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. An LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom if follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal.
3. Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces.
4. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces.
5. Materials, if any, accumulated on the tank bottom (e.g., sediment, silt) are removed to allow for complete inspections of the tank's surfaces.
6. At least 25 percent of the tank's surface is inspected using a method capable of precisely determining wall thickness. The inspection method should be demonstrated capable of detecting both general and pitting corrosion.
7. At least one tank for each material and environment combination should be inspected.
8. For tanks with tightly adhering insulation without evidence of damage to the moisture barrier, inspections may consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation. For tanks with caulking or sealant at the concrete to tank interface, visual inspection of the caulking or sealant is performed in conjunction with physical manipulation of the caulking or sealant.
9. An inspection will be performed prior to December 31, 2019. Subsequent inspections are not required if an evaluation conducted prior to December 31, 2019 and at the scheduled time of each subsequent inspection during the PEO demonstrates the absence of chlorides or other deleterious compounds at sufficient levels to cause pitting corrosion, crevice corrosion, or cracking. The evaluation should include soil sampling in the vicinity of the tank (because soil results indicate atmospheric fallout accumulating in the soil and potentially affecting tank surfaces) and sampling of residue on the top and sides of the tank.
10. A minimum of either 25 sections of the tank's surface (e.g., 1-square-foot sections for tank surfaces, 1-linear-foot sections of weld length) or 20 percent of the tank's surface are examined. The sample inspection points are distributed in such a way that inspections occur in those areas most susceptible to degradation (i.e., areas where contaminants could collect, inlet and outlet nozzles, welds).

11. The first inspection will be performed during the first 10 years of the period of extended operation. Subsequent inspections are not required if evaluations conducted at the time of the first inspection and at the scheduled time of each subsequent inspection during the PEO demonstrate that the soil under the tank is not corrosive using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity. The evaluation should include soil sampling from underneath the tank.

Enhancements will be implemented prior to prior to December 31, 2019 ~~the period of extended operation~~.

A.3.1.10 External Surfaces Monitoring Program

The External Surfaces Monitoring Program is an existing program that inspects external surfaces of components subject to aging management review. The program is also credited with managing loss of material from internal surfaces, for situations in which internal and external material and environment combinations are the same such that external surface condition is representative of internal surface condition.

Surfaces that are inaccessible during plant operations are inspected during refueling outages. ~~Surfaces that are insulated are inspected when the external surface is exposed (i.e., during maintenance).~~ Periodic representative surface condition inspections of the in-scope mechanical indoor components under insulation (with process fluid temperature below the dew point) and outdoor components under insulation will be performed during each 10-year period of the period of extended operation. Surfaces are inspected at frequencies to assure the effects of aging are managed such that applicable components will perform their intended function during the period of extended operation.

The External Surfaces Monitoring Program will be enhanced to include the following.

- Guidance documents will be revised to require periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(2).

- Procedures will be revised to specify the following for insulated components.

  - Periodic representative inspections for CUI will be conducted during each 10-year period of the PEO.

  - For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point), and insulated outdoor components, insulation will be removed for visual inspection of component surfaces. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum) or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type.

  - Inspection locations will be based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components that are alternately wet and dry in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point.

Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection:

- No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction.
- No evidence of cracking.

If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation will continue.

- Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Tightly adhering insulation that is impermeable to moisture will be removed to allow for inspection if there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Components with tightly adhering insulation constitute a separate population from the remainder of in-scope insulated components. The entire population of in-scope accessible component surfaces covered with tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of components with other types of insulation. These inspections will not be credited towards the inspection quantities for components with other types of insulation.

Enhancements will be implemented prior to December 31, 2019 ~~the period of extended operation~~.

A.3.1.13 Fire Water System Program

The Fire Water System Program is an existing program that manages water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, fire pump casings, water storage tanks, standpipes, piping, and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes ~~and standards~~. Such testing assures functionality of systems. To determine if ~~significant~~ abnormal corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections are conducted. In addition to NFPA codes, portions of the water-based fire protection system (a) that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect are subject to augmented testing and inspections. Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

In addition, visual inspection results that identify excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program, and a follow-up volumetric wall thickness examination will be performed. ~~wall thickness evaluations of fire protection piping are periodically performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion.~~

A sample of sprinkler heads required for 10 CFR 50.48 will be inspected using the guidance of NFPA 25 (2011~~02~~ Edition) Section 5.3.1.1.1, which states, "Where sprinklers have been in ~~place~~ service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be tested ~~submitted to a recognized testing laboratory for field service testing~~." This sampling will be repeated every ten years after initial field service testing.

The Fire Water System Program will be enhanced to include the following.

- Revise applicable procedures to include inspection of hose reels for corrosion. In addition, revise the Aacceptance criteria ~~will be revised~~ to verify no unacceptable signs of degradation.

- Revise Fire Water System Program procedures to replace or test closed ~~S~~sprinkler heads required for 10 CFR 50.48 ~~will be replaced or a sample tested using guidance of~~ in accordance with NFPA 25 (2011~~02~~ ~~e~~Edition), Section 5.3.1.~~1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.~~

- ~~Wall thickness evaluations of fire protection piping will be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function.~~

- Revise Fire Water System Program ~~applicable~~ procedures to inspect the internal surface of the foam-based fire suppression tanks at least once every 10 years. Acceptance criteria will be enhanced to verify no ~~significant~~ abnormal corrosion.

- Revise Fire Water System Program procedures to inspect the nozzles in the charcoal filter units for abnormal corrosion when the charcoal is replaced. (Refer to NFPA-25 (2011 Edition), Sections 13.4.3.2.2 and 14.2.)

- Revise Fire Water System Program procedures to inspect for and require replacement of sprinkler heads (nozzles) if they show signs of abnormal corrosion, excessive loading, leakage, or if the glass bulb heat responsive element is found empty. (Refer to NFPA-25 (2011 Edition), Section 5.2.1.1.)

- Revise Fire Water System Program procedures to perform main drain testing in accordance with NFPA 25 (2011 Edition), Section 13.2.5, on 20 percent of the testable automatic standpipes with at least one main drain test in each building. (Refer to NFPA-25 (2011 Edition), Sections 6.3.1.5 and 13.2.5)

- Revise Fire Water System Program procedures to inspect the interior and exterior of the fire water storage tanks in accordance with NFPA 25 (2011 Edition), Section 9.2.5.5, 9.2.6 and 9.2.7, with the exception of NFPA Sections 9.2.7.1 and 9.2.7.6. In lieu of testing specified in Section 9.2.7.1, perform holiday testing. In lieu of testing specified in Section 9.2.7.6, perform ultrasonic thickness checks or mechanical measurements of any identified corroded areas at least once every five years.

- Revise Fire Water System Program procedures to perform an air flow test each refueling outage through the foam system open-head nozzles to ensure there is no blockage, and in the event blockage is identified provide instruction that the system shall be cleaned and retested. (Refer to NFPA-25 (2011 Edition), Section 13.4.3.2.2.)

- Revise Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions every five years, or after an extended shutdown of greater than one year, by opening a flushing connection at the end of one main and by removing a closed sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could results in flow obstructions or blockage of sprinkler heads or nozzles. In the event there are multiple wet pipe systems in a structure, one third will be inspected every five years such that all systems will be inspected during each 15-year period. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

- Revise Fire Water System Program procedures to perform an obstruction evaluation if any of the following conditions exist. (Refer to NFPA-25 (2011 Edition), Section 14.3.1.)

- There is an excessive discharge of material during routine flow tests.
- An inspector's test valve is clogged during routine testing.
- Foreign materials are identified during internal inspections.
- Sprinkler heads are found clogged during removal or testing.
- Pin hole leaks are identified in fire water piping.
- After an extended shutdown.
- There is a 50 percent increase in time it takes for water to flow out the inspector test valve after the associated dry valve is tripped when compared to the original acceptance criteria or last test.

- Revise Fire Water System Program procedures to perform a wall thickness evaluation of any areas identified with excessive accumulation of corrosion products or appreciable localized pitting beyond a normal oxide layer and enter the condition into the corrective action program. (Refer to LR-ISG-2012-02, Section C, iii, (c).)

- Revise Fire Water System Program procedure(s) to test and inspect the water spray system #11 - charcoal filters associated with the containment purge exhaust, primary auxiliary building exhaust system, and containment pressure relief filtration units in accordance NFPA 25 (2011 Edition) Section 13.4.3.2.2, and the associated sub-steps.

- Revise Fire Water System Program procedure(s) to fully open hydrants, flush at least for one minute, flush until the water is clear, and verify the hydrants drainage takes no longer than 60 minutes. Where drainage is longer than 60 minutes, provide procedural steps to address the situation (e.g., unclog the drain or pump out the hydrant). (Refer to NFPA-25 (2011 Edition), Section 7.3.2)

- Revise Fire Water System Program procedure(s) to perform an air test to ensure spray patterns are not affected by plugged nozzles associated with the hydrogen seal oil unit, main boiler feed pump oil reservoir, main lube oil storage, and main lube oil reservoir foam deluge systems. Where plugged nozzles are identified, the procedure(s) should include a requirement to clean and retest. (Refer to NFPA-25 (2011 Edition), Section 13.4.3.2.2.)

- Revise Fire Water System Program procedure(s) to remove, clean and inspect the strainers associated with electric tunnels and the containment purge exhaust system, primary auxiliary building exhaust system, and containment pressure relief filtration unit for damage and abnormal corrosion. (Refer to NFPA-25 (2011 Edition), Section 10.2.1.7.)

- Revise Fire Water System Program procedure(s) to perform an internal inspection every five years of the dry portion of the preaction system associated with the electric tunnels by removing a sprinkler toward the end of one branch line or using the inspector test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedure that governs inspection of the normally dry piping will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2)

acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

- Revise Fire Water System Program procedure(s) to perform an internal inspection every five years of the most remote dry piping downstream of the deluge valves in the deluge systems for the primary auxiliary building exhaust, containment purge, containment pressure relief, and foam systems by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedure that governs inspection of the normally dry piping will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

Enhancements will be implemented prior to December 31, 2019 ~~the period of extended operation~~.

A.3.1.33 Service Water Integrity Program

The Service Water Integrity Program will be enhanced to include the following.

- Revise the appropriate procedures to incorporate actions to manage corrosion issues.
    - When through-wall leaks are detected, the leakage is evaluated under the corrective action program, which includes operability or functionality assessment of structural integrity and determination of appropriate corrective action.
    - Accessible portions of safety-related buried service water piping will be internally inspected by robotic crawler or manual crawl-through once during the first 10 years of the period of extended operation

The enhancement will be implemented prior to December 31, 2019.

B.1.1 ABOVEGROUND STEEL TANKS

Program Description

The Aboveground Steel Tanks Program is an existing program that manages loss of material and cracking of the outside and inside ~~from external~~ surfaces of aboveground ~~carbon steel~~ tanks constructed on concrete or soil. ~~by periodic visual inspection of external surfaces and thickness measurement of locations that are inaccessible for external visual inspection.~~ Outdoor tanks (except fire water storage tanks) are included (IPEC has no indoor tanks that meet the criteria of LR-ISG-2012-02 for inclusion in this program). For tanks where the exterior surface is fully visible, that surface may be inspected under the program for inspection of external surfaces (Ref. Section B.1.11) in lieu of the visual inspections recommended in this AMP; surface examinations are conducted in accordance with the provisions of this AMP. This program credits the standard industry practice of coating or painting the external surfaces of steel tanks as a preventive measure to mitigate corrosion. The program relies on periodic inspections to monitor degradation of the protective paint or coating. Tank inside surfaces are inspected by visual or surface examinations as required to detect applicable aging effects.

For storage tanks supported on earthen or concrete foundations, corrosion may occur at inaccessible locations, such as the tank bottom. Accordingly, verification is performed to ensure that significant degradation in inaccessible locations is not occurring and that the function is maintained during the period of extended operation. An acceptable verification consists of thickness measurements of the tank bottom surface.

The Aboveground Steel Tanks Program will be enhanced to include the following tank inspection details[1].

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Inspections to identify degradation of inside surfaces of tank shell, roof[3], and bottom Inside Surface (IS), Outside Surface (OS)[4, 5]				
Steel	Treated water	Loss of material	Volumetric from OS[6] or visual from IS	One time prior to December 31, 2019[7]
Stainless Steel	Treated water	Loss of material	Volumetric from OS[6] or Visual from IS	One time prior to December 31, 2019[7]
Inspections to identify degradation of external surfaces of tank roof, tank shell, and bottom not exposed to soil or concrete[8]				

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Steel	Air-indoor uncontrolled Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
Stainless Steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking	Surface[9, 10]	Each 10-year period of the period of extended operation
Inspections to identify degradation of tank bottoms and tank shells exposed to soil or concrete				
Steel	Soil or concrete	Loss of material	Volumetric from IS	Each 10-year period of the period of extended operation[11]
Stainless Steel	Soil or concrete	Loss of material	Volumetric from IS	Each 10-year period of the period of extended operation[11]

Tank Inspection Table Notes

1. IPEC LRA section B.1.9, "Diesel Fuel Monitoring" manages loss of material on the internal surfaces of fuel oil storage tanks.
2. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g. inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated effective at detecting the AERM and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low-frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. An LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom if follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal.
3. Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces.
4. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces.
5. Materials, if any, accumulated on the tank bottom (e.g., sediment, silt) are removed to allow for complete inspections of the tank's surfaces.
6. At least 25 percent of the tank's surface is inspected using a method capable of precisely determining wall thickness. The inspection method should be demonstrated capable of detecting both general and pitting corrosion.
7. At least one tank for each material and environment combination should be inspected.
8. For tanks with tightly adhering insulation without evidence of damage to the moisture barrier, inspections may consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation. For tanks with caulking or sealant at the concrete to tank interface, visual inspection of the caulking or sealant is performed in conjunction with physical manipulation of the caulking or sealant.
9. An inspection will be performed prior to December 31, 2019. Subsequent inspections are not required if an evaluation conducted prior to December 31, 2019 and at the scheduled time of each subsequent inspection during the PEO demonstrates the absence of chlorides or other deleterious compounds at sufficient levels to cause pitting corrosion, crevice corrosion, or cracking. The

evaluation should include soil sampling in the vicinity of the tank (because soil results indicate atmospheric fallout accumulating in the soil and potentially affecting tank surfaces) and sampling of residue on the top and sides of the tank.

10. A minimum of either 25 sections of the tank's surface (e.g., 1-square-foot sections for tank surfaces, 1-linear-foot sections of weld length) or 20 percent of the tank's surface are examined. The sample inspection points are distributed in such a way that inspections occur in those areas most susceptible to degradation (i.e., areas where contaminants could collect, inlet and outlet nozzles, welds).
11. The first inspection will be performed during the first 10 years of the period of extended operation. Subsequent inspections are not required if evaluations conducted at the time of the first inspection and at the scheduled time of each subsequent inspection during the PEO demonstrate that the soil under the tank is not corrosive using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity. The evaluation should include soil sampling from underneath the tank.

NUREG-1801 Consistency

The Aboveground Steel Tanks Program is consistent with the program described in NUREG-1801, Section XI.M29, Aboveground ~~Steel~~ Metallic Tanks, as modified by LR-ISG-2012-02 with exceptions and enhancements.

Exceptions to NUREG-1801

~~None~~

The Aboveground Steel Tanks Program is consistent with the program described in NUREG-1801, Section XI.M29, Aboveground Steel Tanks, as modified by LR-ISG-2012-02, with the following exception.

Attributes Affected	Exception
4. Detection of Aging Effects	The timing of inspections under detection of aging effects is not consistent with LR-ISG-2012-02 recommendations.[1]

Exception Note

1. The issue date of the ISG upon which program changes are based precluded the performance of the added inspections prior to the period of extended operation. Operating experience, including tank inspections results, to date indicates that aging effects are being adequately managed and supports the acceptability of performing inspections as specified in the program description.

Enhancements

The following enhancements will be implemented prior to ~~the period of extended operation~~ December 31, 2019.

Attributes Affected	Enhancement
4. Detection of Aging Effects 6. Acceptance Criteria	~~Revise applicable procedures to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank (IP2), tanks, once during the first ten years of the period of extended operation.~~ Develop or revise program implementing documents as necessary to incorporate the tank inspection details delineated in the table in the program description.
5. Monitoring and Trending	Revise applicable ~~procedures~~ implementing documents to require trending of thickness measurements when material loss is detected.

Operating Experience

Thickness measurements of portions of the city water tank were performed in 2003 with satisfactory results (tank was determined to be in good condition). Thickness measurements of the IP2 condensate storage tank in 2008 identified minor corrosion. There was no loss of intended function.

The visual inspection and thickness measurement methods used in this program to detect aging effects are proven industry techniques that have been effectively used at IPEC. Operating experience with these techniques assures that implementation of the Aboveground Steel Tanks Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.
~~Thickness measurements of the gas turbine fuel storage tanks in April 2002 found pitting up to 60% through-wall, with no loss of intended function. This was repaired with a weld overlay.~~

~~Internal inspections of the IP2 fire water storage tank and the training center fire water storage tank in 2003 detected failure of the coating in several places, but no appreciable metal loss was identified. Corrective actions were issued to repair the coating.~~

~~Identification of degradation and performance of corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects for passive components.~~

B.1.11 EXTERNAL SURFACES MONITORING

Surfaces that are inaccessible during plant operations are inspected during refueling outages. ~~Surfaces that are insulated are inspected when the external surface is exposed (i.e., during maintenance).~~ Periodic representative surface condition inspections of the in-scope mechanical indoor components under insulation (with process fluid temperature below the dew point) and outdoor components under insulation will be performed during each 10-year period of the period of extended operation. Surfaces are inspected at frequencies to assure the effects of aging are managed such that applicable components will perform their intended function during the period of extended operation.

NUREG-1801 Consistency

The External Surfaces Monitoring Program is consistent with the program described in NUREG-1801, Section XI.M36, External Surfaces Monitoring with ~~an~~ enhancements.

...

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to ~~the period of extended operation~~ December 31, 2019.

Attributes Affected	Enhancement
4. Detection of Aging Effects	Revise External Surfaces Monitoring Program procedures to specify the following for insulated components. • Periodic representative inspections for CUI will be conducted during each 10-year period of the PEO. • For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point) and insulated outdoor components, insulation will be removed for visual inspection of component surfaces. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum) or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a

	minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type. • Inspection locations will be based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components that are alternately wet and dry in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point. Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection: ➢ No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction. ➢ No evidence of cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue. • Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Tightly adhering insulation that is impermeable to moisture will be removed to allow for inspection if there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Components with tightly adhering insulation constitute a separate population from the remainder of in-scope insulated components. The entire population of in-scope accessible component surfaces covered with tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of components with other types of insulation. These inspections will not be credited towards the inspection quantities for components with other types of insulation.

B.1.14 FIRE WATER SYSTEM

Program Description

The Fire Water System Program is an existing program that manages water-based fire protection systems consisting of sprinklers, nozzles, fittings, valves, hydrants, hose stations, fire pump casings, water storage tanks, standpipes, piping, and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes ~~and standards~~. Such testing assures functionality of systems. To determine ~~if significant~~ abnormal corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections are conducted. In addition to NFPA codes, portions of the water-based fire protection system (a) that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect are subject to augmented testing and inspections. Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

In addition, visual inspection results that identify excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program, and a follow-up volumetric wall thickness examination will be performed. ~~wall thickness evaluations of fire protection piping are periodically performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion~~.

A sample of sprinkler heads required for 10 CFR 50.48 will be inspected using the guidance of NFPA 25 (2011~~02~~ E~~e~~dition) Section 5.3.1.1.1, which states, "Where sprinklers have been in ~~place~~ service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be tested ~~submitted to a recognized testing laboratory for field service testing~~." This sampling will be repeated every 10 years after initial field service testing.

NUREG-1801 Consistency

The Fire Water System Program ~~is~~ with enhancements will be consistent with the program described in NUREG-1801, Section XI.M27, Fire Water System, as modified by LR-ISG-2012-02, with ~~an~~ exceptions ~~and enhancements~~.

Exceptions to NUREG-1801

The Fire Water System Program ~~is~~ with enhancements will be consistent with the program described in NUREG-1801, Section XI.M27, Fire Water System, as modified by LR-ISG-2012-02 with the following exceptions.

Attributes Affected	Exception
4. Detection of Aging Effects	1. NUREG-1801 specifies annual fire hose hydrostatic tests and gasket inspections. Fire hoses and hose station gaskets are not subject to aging management review and not included in the program. [1] 2. NFPA 25 (2011 Edition), Section 5.2.1 specifies annual sprinkler inspections. IP2 performs inspections of the EDG wet pipe sprinklers on 18-month intervals.[2] 3. NFPA 25 (2011 Edition), Section 13.4.3.2.2 specifies trip testing deluge valves on an annual basis. The deluge valve for the IP2 primary auxiliary building exhaust, containment building purge exhaust and containment building pressure relief charcoal units are tested each refueling outage, which is every two years.[3] 4. NFPA 25 (2011 Edition), Section 5.2.1.1 specifies inspections for sprinkler orientation, foreign material, physical damage, paint, and loading due to dust or debris. Sprinkler orientation, foreign material, physical damage, and paint are event driven. Therefore, inspections for these conditions are not included in the Fire Water System Aging Management Program.[4] 5. During an inspection in accordance with NFPA 25 (2011 Edition), Sections 9.2.6.4 and 9.2.7.1 specify an evaluation of interior tank coatings in accordance with the adhesion test of ASTM D 3359. Standard Test Methods for Measuring Adhesion by Tape Test, generally referred to as the "cross-hatch test," when indications are identified in the fire water, tank coating. IPEC performs holiday testing. In addition, IPEC performs ultrasonic thickness

	checks or mechanical measurements of any identified corroded areas at least once every five years. IPEC does not apply the cross-hatch test.[5] 6. NFPA 25 (2011 Edition), Section 9.7.2.1 specifies vacuum box testing of fire water tanks that are designed with a flat bottom. The IPEC fire water tanks were designed to have flat bottom. However, performing vacuum box testing to identify leakage may not be possible in the event the bottom of the tanks is uneven.[6] 7. NFPA 25 (2011 Edition), Sections 6.3.1.5 and 13.2.5 specifies main drain testing on all standpipes and risers in the water-based fire suppression system with automatic water supplies to determine if there has been a change in the water supply piping and control valves. IPEC does not perform main drain testing on all standpipes and risers.[7] 8. NFPA 25 (2011 Edition), Section 13.4.3.2.3 specifies performing preaction valve trip testing with the control valve fully open. IP2 does not perform the preaction valve with the control valve fully open for the electric tunnels.[8] 9. NFPA 25 (2011 Edition), Section 14.2.1 specifies an internal inspection for blockage every five years of normally dry fire water piping that may experience periodic wetting. IPEC does not perform these interior inspections of the dry piping downstream of the deluge valves for the transformers.[9] 10. NFPA 25 (2011 Edition), Section 5.3.1 requires an annual inspection of sprinkler heads for leakage. IPEC does not inspect open sprinkler heads for leakage.[10]

Exception Notes

1 Fire hoses are periodically inspected, hydrotested, and replaced as required in accordance with plant procedures. Gaskets in couplings are replaced during hose station inspections.
2 Inspection once every 18 months has been effective at maintaining component intended functions.
3 Testing is feasible only during refueling outages, which occur once every 24 months. Testing once every 24 months has been effective at maintaining component intended functions.
4 IP2 and IP3 address the identified conditions during design, installation and operation of the fire water system rather than in an aging management program because they are not issues attributable to the effects of aging.
5 The fire water tanks at IPEC have a capacity of 300,000 and 350,000 gallons with continuous monitoring through instrumentation with alarms in the control room. The adhesion testing suggested in NFPA 25 (2011 Edition), Section 9.2.7, Item #1 (ASTM D 3359) is a destructive test that requires cutting an 'X' in the coating down to the substrate in a number of locations. According to ASTM D 3359, this testing of coating adhesion is not a precise test of coating adhesion and it is not unexpected to get different test results from different personnel performing the same test. Different test results occur because the test depends on (1) the peel angle and rate, (2) subjective visual assessment of any coating removed, and (3) humidity and temperature. The repair of the coating adhesion test locations would require a specific humidity and temperature. For these reasons, the adhesion test is not considered a prudent inspection method.
6 The fire water tanks at IPEC have a capacity of 300,000 and 350,000 gallons with continuous monitoring through instrumentation with alarms in the control room. Jockey pumps provide makeup to compensate for leakage from the system. Leakage in excess of jockey pump makeup capacity would be obvious to the operating staff and would result in corrective actions to identify and repair the source of the leakage. Therefore, the vacuum box testing is not necessary to ensure the tanks remain capable of fulfilling their license renewal intended functions.
7 IPEC has committed to performing main drain tests in accordance with NFPA 25 (2011 Edition), Section 13.2.5, on 20 percent of the testable automatic standpipes and risers with at least one main drain test per building. Additional main drain testing in radiologically controlled areas and areas that contain equipment critical for normal and shutdown operations creates additional radwaste and increases operational risk.
8 Performing trip testing of the preaction valves for the IPEC electrical tunnels with the control valve in a closed or throttled position limits the amount of water that enters the piping designed to be dry downstream of the preaction valve.
9 The deluge systems for the transformers are full flow tested every refueling outage and any blockage would be identified during that testing.
10 Leakage from an open sprinkler head indicates a leaking deluge or control valve. Such leakage is due to degradation of the active subcomponents of the valves which are not subject to aging management review for license renewal. The Fire Water System Aging Management Program is not appropriate for managing degradation of active subcomponents.

Enhancements

The following enhancements will be implemented prior to ~~the period of extended operation~~ December 31, 2019.

Attributes Affected	Enhancements
3. Parameters Monitored or Inspected 6. Acceptance Criteria	Revise applicable procedures to include inspection of hose reels for corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Revise ~~applicable~~IP2 and IP3 Fire Water System Program procedures to inspect the internal surface of the foam based fire suppression tanks at least once every 10 years. Acceptance criteria will be enhanced to verify no ~~significant~~ abnormal corrosion.
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to replace or test closed ~~S~~sprinkler heads required for 10 CFR 50.48 ~~will be replaced or a sample tested using guidance of~~ in accordance with NFPA 25 (2011~~02~~ ~~e~~Edition), Section 5.3.1.~~1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.~~
~~4. Detection of Aging Effects~~	~~Wall thickness evaluations of fire protection piping will be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function.~~
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to inspect for and require replacement of sprinkler heads (nozzles) if they show signs of abnormal corrosion, excessive loading, leakage, or if the glass bulb heat responsive element is found empty. (Refer to NFPA-25 (2011 Edition), Section 5.2.1.1.)
4. Detection of Aging Effects	Revise IP2 Fire Water System Program procedures acceptance criteria for the primary auxiliary building exhaust, containment building purge exhaust, and containment building pressure relief charcoal units to ensure partial flow blockage can be detected during air flow testing. (Refer to NFPA-25 (2011 Edition), Section 13.4.3.2.2.)

Attributes Affected	Enhancements
4. Detection of Aging Effects	Revise IP2 Fire Water System Program procedures to inspect the nozzles in the charcoal filter units for abnormal corrosion when the charcoal is replaced. (Refer to NFPA-25 (2011 Edition), Sections 13.4.3.2.2 and 14.2.)
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to perform main drain testing in accordance with NFPA 25 (2011 Edition), Section 13.2.5, on 20 percent of the testable automatic standpipes with at least one main drain test in each building. (Refer to NFPA-25 (2011 Edition), Sections 6.3.1.5 and 13.2.5.)
4. Detection of Aging Effects	Revise Fire Water System Program procedures to inspect the interior and exterior of the fire water storage tanks in accordance with NFPA 25 (2011 Edition), Sections 9.2.5.5, 9.2.6 and 9.2.7, with the exception of NFPA Sections 9.2.7.1 and 9.2.7.6. In lieu of testing specified in Section 9.2.7.1, perform holiday testing. In lieu of testing specified in Section 9.2.7.6, perform ultrasonic thickness checks or mechanical measurements of any identified corroded areas at least once every five years.
4. Detection of Aging Effects	Revise IP2 Fire Water System Program procedures to inspect and test the deluge system for the boric acid building filter units every two years in accordance with NFPA 25 (2011 Edition) 13.4.3.2.2.
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to perform an air flow test each refueling outage through the foam system open head nozzles to ensure there is no blockage, and in the event blockage is identified provide instruction that the system shall be cleaned and retested. (Refer to NFPA-25 (2011 Edition), Section 13.4.3.2.2.)
4. Detection of Aging Effects	Revise IP2 Fire Water System Program procedures to remove, inspect for damage and corroded parts, and clean the strainers associated with the supply line to the electric tunnel (refer to DWG LRA-227551-0, Detail B, Coordinate (D-6)), and in the line downstream of the deluge valve for the primary auxiliary building exhaust and containment building purge filtration units ((refer to DWG LRA-227551-0, Detail E, Coordinate (E-4)) every five years, or after each flow test. (Refer to NFPA-25 (2011 Edition), Section 10.2.1.7.)

Attributes Affected	Enhancements
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions every five years, or after an extended shutdown of greater than one year, by opening a flushing connection at the end of one main and by removing a closed sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler head or nozzles. In the event there are multiple wet pipe systems in a structure, one third will be inspected every five years such that all systems will be inspected during each 15-year period. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)
4. Detection of Aging Effects	Revise IP2 Fire Water System Program procedures to perform an internal inspection of dry piping every five years, or after an extended shutdown of greater than one year, for the preaction systems associated with the technical support center computer and uninterruptible power supply room, and the preaction system associated with the electric tunnels by removing a sprinkler toward the end of one branch line or using the inspectors test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

Attributes Affected	Enhancements
4. Detection of Aging Effects	Revise IP2 Fire Water System Program procedures to perform an internal inspection of the most remote dry piping downstream of the deluge valves every five years, or after an extended shutdown of greater than one year, for the deluge systems associated with the for the primary auxiliary building, containment purge, containment ventilation, and boric acid building charcoal filters, and the foam deluge systems by removing a sprinkler toward the end of one branch line or using the inspectors test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to perform an obstruction evaluation if any of the following conditions exist. (Refer to NFPA-25 (2011 Edition), Section 14.2.) • There is an excessive discharge of material during routine flow tests. • An inspector's test valve is clogged during routine testing. • Foreign materials are identified during internal inspections. • Sprinkler heads are found clogged during removal or testing. • Pin hole leaks are identified in fire water piping. • After an extended shutdown. • There is a 50% increase in time it takes for water to flow out the inspector test valve after the associated dry valve is tripped when compared to the original acceptance criteria or last test.
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to perform a wall thickness evaluation of any areas identified with excessive accumulation of corrosion products or appreciable localized pitting beyond a normal oxide layer and enter the condition into the corrective action program.

Attributes Affected	Enhancements
	(Refer to LR-ISG-2012-02, Section C, iii, (c).)
4. Detection of Aging Effects	Revise IP3 Fire Water System Program procedure(s) to test and inspect the water spray system #11 - Charcoal filters associated with the containment purge exhaust, primary auxiliary building exhaust system, and containment pressure relief filtration units in accordance NFPA 25(2011 Edition) Section 13.4.3.2.2, and the associated sub-steps.
4. Detection of Aging Effects	Revise IP3 Fire Water System Program procedure(s) to fully open hydrants, flush at least for one minute, flush until the water is clear, and verify the hydrants drainage takes no longer than 60 minutes. Where drainage is longer than 60 minutes, provide procedural steps to address the situation (e.g., unclog the drain or pump out the hydrant). (Refer to NFPA-25 (2011 Edition), Section 7.3.2.)
4. Detection of Aging Effects	Revise IP3 Fire Water System Program procedure(s) to perform an air test to ensure spray patterns are not affected by plugged nozzles associated with the hydrogen seal oil unit, main boiler feed pump oil reservoir, main lube oil storage, and main lube oil reservoir foam deluge systems. Where plugged nozzles are identified, the procedure(s) should include a requirement to clean and retest. (Refer to NFPA-25 (2011 Edition), Section 13.4.3.2.2.)
4. Detection of Aging Effects	Revise IP3 Fire Water System Program procedure(s) to remove, clean and inspect the strainers associated with electric tunnels and the containment purge exhaust system, primary auxiliary building exhaust system, and containment pressure relief filtration unit for damage and abnormal corrosion. (Refer to NFPA-25 (2011 Edition), Section 10.2.1.7.)
4. Detection of Aging Effects	Revise IP3 Fire Water System Program procedure(s) to perform an internal inspection every five years of the remote normally dry portion of the preaction system associated with the with the electric tunnels by removing a sprinkler toward the end of one branch line or using the inspector test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedure that governs

Attributes Affected	Enhancements
	inspection of the normally dry piping will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)
4. Detection of Aging Effects	Revise IP3 Fire Water System Program procedure(s) to perform an internal inspection every five years of the most remote dry piping downstream of the deluge valves in the deluge systems for the primary auxiliary building exhaust, containment purge, containment pressure relief, and foam systems by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedure that governs inspection of the normally dry piping will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

B.1.34 SERVICE WATER INTEGRITY

Enhancements
~~None~~

The following enhancement will be implemented prior to December 31, 2019.

Attributes Affected	Enhancements
4. Detection of Aging Effects	Revise the appropriate procedures to incorporate actions to manage corrosion issues. • When through-wall leaks are detected, the leakage is evaluated under the corrective action program, which includes operability or functionality assessment of structural integrity and determination of appropriate corrective action. • Accessible portions of safety-related buried service water piping will be internally inspected by robotic crawler or manual crawl-through once during the first 10 years of the period of extended operation.

ATTACHMENT 3 TO NL-14-147

LICENSE RENEWAL APPLICATION

IPEC LIST OF REGULATORY COMMITMENTS

Rev. 25

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

List of Regulatory Commitments

Rev. 25

The following table identifies those actions committed to by Entergy in this document.

Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: Complete ~~IP3: December 12, 2015~~	NL-07-039 NL-13-122	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1, A.3.1.1 and B.1.1, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.1 A.3.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: Complete IP3: Complete	NL-07-039 NL-07-153 NL-13-122	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection. Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using inspection techniques with demonstrated effectiveness.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-09-106 NL-09-111 NL-11-101	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit items 128, 129, 132, 491, 492, 510

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents to the storage tanks. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.			
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	IP2: Complete ~~IP3: December 12, 2015~~	NL-07-039 NL-13-122	A.2.1.10 A.3.1.10 B.1.11
	Implement LRA Sections A.2.1.10, A.3.1.10 and B.1.11, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.10 A.3.1.10 B.1.11

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.11 A.3.1.11 B.1.12, Audit Item 164
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	A.2.1.12 A.3.1.12 B.1.13

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: Complete ~~IP3: December 12, 2015~~	NL-07-039 NL-13-122 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106
	Implement LRA Sections, A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.13 A.3.1.13 B.1.14

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	A.2.1.15 A.3.1.15 B.1.16

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-09-018	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52
11	Deleted		NL-09-056 NL-11-101	

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-057 NL-13-077	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	A.2.1.21 A.3.1.21 B.1.22

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-11-032 NL-11-096 NL-11-101	A.2.1.22 A.3.1.22 B.1.23 Audit item 173
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.24 A.3.1.24 B.1.25 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with the oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-11-101	A.2.1.25 A.3.1.25 B.1.26
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.26 A.3.1.26 B.1.27 Audit item 173
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.27 A.3.1.27 B.1.28 Audit item 173
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	A.2.1.28 A.3.1.28 B.1.29

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.32 A.3.1.32 B.1.33 Audit item 173
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.34 A.3.1.34 B.1.35
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building-elevated passageway (IP2) • new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3)	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-057 NL-13-077	A.2.1.35 A.3.1.35 B.1.36 Audit items 86, 87, 88, 417

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	• security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material. Enhance the Structures Monitoring Program for IP2		NL-13-077	

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO. Enhance the Structures Monitoring Program to include more detailed quantitative acceptance criteria for inspections of concrete structures in accordance with ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures" prior to the period of extended operation.		NL-08-127 NL-11-032 NL-11-101	Audit Item 360 Audit Item 358
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.36 A.3.1.36 B.1.37 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: Complete	NL-07-039 NL-13-122	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-11-107	A.2.1.41 A.3.1.41
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	IP3: December 12, 2015	NL-07-039 NL-08-127	A.3.2.1.4 4.2.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
33	At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following: (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF. (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-021 NL-10-082	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit item 146
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	Complete	NL-13-122 NL-07-078 NL-08-074 NL-11-101	2.1.1.3.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Any degradation will be evaluated for updating of the containment liner analyses as needed.	IP2: Complete IP3: December 12, 2015	NL-08-127 NL-13-122 NL-11-101 NL-09-018	Audit Item 27
36	Perform a one-time inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation. A sample of leakage fluid will be analyzed to determine the composition of the fluid. If additional core samples are taken prior to the end of the first ten years of the period of extended operation, a sample of leakage fluid will be analyzed.	IP2: Complete	NL-08-127 NL-11-101 NL-13-122 NL-09-056 NL-09-079	Audit Item 359
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	IP2: Complete IP3: Complete	NL-08-127 NL-13-122	Audit Item 361

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RTpts or C_VUSE, updated calculations will be provided to the NRC.	IP2: Complete IP3: December 12, 2015	NL-08-143 NL-13-122	4.2.1
39	Deleted		NL-09-079	
40	Evaluate plant specific and appropriate industry operating experience and incorporate lessons learned in establishing appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs. Documentation of the operating experience evaluated for each new program will be available on site for NRC review prior to the period of extended operation.	IP2: Complete IP3: December 12, 2015	NL-09-106 NL-13-122	B.1.6 B.1.22 B.1.23 B.1.24 B.1.25 B.1.27 B.1.28 B.1.33 B.1.37 B.1.38
41	IPEC will inspect steam generators for both units to assess the condition of the divider plate assembly. The examination technique used will be capable of detecting PWSCC in the steam generator divider plate assembly. The IP2 steam generator divider plate inspections will be completed within the first ten years of the period of extended operation (PEO). The IP3 steam generator divider plate inspections will be completed within the first refueling outage following the beginning of the PEO.	IP2: After the beginning of the PEO and prior to September 28, 2023 IP3: Prior to the end of the first refueling outage following the beginning of the PEO.	NL-11-032 NL-11-074 NL-11-090 NL-11-101	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
42	IPEC will develop a plan for each unit to address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds using one of the following two options. Option 1 (Analysis) IPEC will perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary in which the tube-to-tubesheet weld is no longer included and, therefore, is not required for reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary must be approved by the NRC as a license amendment request. Option 2 (Inspection) IPEC will perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified: a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.	IP2: Prior to March 2024 IP3: Prior to the end of the first refueling outage following the beginning of the PEO. IP2: Between March 2020 and March 2024 IP3: Prior to the end of the first refueling outage following the beginning of the PEO.	NL-11-032 NL-11-074 NL-11-090 NL-11-096	N/A
43	IPEC will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any.	IP2: Complete IP3: Prior to December 12, 2015	NL-11-032 NL-13-122 NL-11-101	4.3.3

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
44	IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS "Design CUF" module.	IP2: Complete IP3: Prior to December 12, 2015	NL-11-032 NL-11-101 NL-13-122	N/A
45	IPEC will not use the NB-3600 option of the WESTEMS program in future design calculations until the issues identified during the NRC review of the program have been resolved.	IP2: Complete IP3: Prior to December 12, 2015	NL-11-032 NL-11-101 NL-13-122	N/A
46	Include in the IP2 ISI Program that IPEC will perform twenty-five volumetric weld metal inspections of socket welds during each 10-year ISI interval scheduled as specified by IWB-2412 of the ASME Section XI Code during the period of extended operation. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.	IP2: Complete	NL-11-032 NL-11-074 NL-13-122	N/A
47	Deleted.		NL-14-093	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
48	Entergy will visually inspect IPEC underground piping within the scope of license renewal and subject to aging management review prior to the period of extended operation and then on a frequency of at least once every two years during the period of extended operation. This inspection frequency will be maintained unless the piping is subsequently coated in accordance with the preventive actions specified in NUREG-1801 Section XI.M41 as modified by LR-ISG-2011-03. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Consistent with revised NUREG-1801 Section XI.M41, such adverse indications will be entered into the plant corrective action program for evaluation of extent of condition and for determination of appropriate corrective actions (e.g., increased inspection frequency, repair, replacement).	IP2: Complete IP3: Prior to December 12, 2015	NL-12-174 NL-13-122	N/A
49	Recalculate each of the limiting CUFs provided in section 4.3 of the LRA for the reactor vessel internals to include the reactor coolant environment effects (F_{en}) as provided in the IPEC Fatigue Monitoring Program using NUREG/CR-5704 or NUREG/CR-6909. In accordance with the corrective actions specified in the Fatigue Monitoring Program, corrective actions include further CUF re-analysis, and/or repair or replacement of the affected components prior to the CUF_{en} reaching 1.0.	IP2: Complete IP3: Prior to December 12, 2015	NL-13-052 NL-13-122	A.2.2.2 A.3.2.2
50	Replace the IP2 split pins during the 2016 refueling outage (2R22).	IP2: Prior to completion of 2R22 IP3: N/A	NL-13-122 NL-14-067	A.2.1.41 B.1.42
51	Implement the enhancements to the Service Water Integrity Program described in LRA Section B.1.34, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.33 A.3.1.33 B.1.34